ACCESSION #: 9002120163
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Palo Verde Unit 3 PAGE: 1 OF 15

DOCKET NUMBER: 05000530

TITLE: Reactor Trip Due to Low Steam Generator Level
EVENT DATE: 03/03/89 LER #: 89-001-03 REPORT DATE: 01/28/90

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 098

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(i) AND 50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
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COMPONENT FAILURE DESCRIPTION:
CAUSE: B SYSTEM: SB COMPONENT: V MANUFACTURER: C600
B JI 69 A160
REPORTABLE NPRDS: Y
Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On March 3, 1989 a approximately 0102 MST Palo Verde Unit 3 was operating at approximately 98 percent power when an electrical grid disturbance resulted in the Main Generator output breakers opening. This resulted in a Reactor Power Cutback (RPCB) and Steam Bypass Control System (SBCS) actuation. An SBCS malfunction resulted in a Steam Generator (S/G) number 2 low pressure reactor trip, turbine trip, Main Steam Isolation Signal, and Containment Isolation Actuation Signal at approximately 0103 MST. Approximately six seconds later, a Safety Injection Actuation Signal occurred as a result of low pressurizer pressure.

Control Room personnel attempted to remove decay heat and control S/G pressure utilizing the Atmospheric Dump Valves (ADV's). Control Room personnel could not remotely operate the ADV's from the Control Room or Remote Shutdown Panel. Heat removal was subsequently established by manually opening the ADV's. In the interim, one Main Steam Safety Valve cycled to remove decay heat and control S/G pressure.

The cause of the reactor trip was a malfunction in the SBCS. An independent investigation has been conducted to determine the causes of the problems occurring during the event. Based upon the investigation, appropriate corrective measures have been developed.

This submittal also provides a Special Report in accordance with Technical Specification 3.5.2 ACTION b.

END OF ABSTRACT

I. DESCRIPTION OF WHAT OCCURRED:

A. Initial Conditions:

Prior to the event described in this LER, Palo Verde Unit 3 was operating in Mode 1 (POWER OPERATION) at approximately 98 percent power. In-plant non-Class 1E electrical loads were being supplied by the Main Turbine-Generator (EL)(TG) via the Unit Auxiliary Transformer (EA) (XFMR). In-plant Class 1E electrical loads were being supplied by off-site power via the Startup Transformers (EA)(XFMR).

B. Reportable Event Description (Including Dates and Approximate Times of Major Occurrences):

Event Classification: Reactor Trip. Engineered Safety Features Actuation. Condition Prohibited by the Plant's Technical Specifications.

At approximately 0102 MST on March 3, 1989 a fault occurred near the Devers, California switchyard which resulted in an electrical disturbance in the off-site power supply system. The electrical disturbance resulted in the operation of the sub-synchronous oscillation protective relaying (RLY) for the Unit 3 Main Turbine-Generator (TA)(TB) which caused the main generator output breakers to open. This large load rejection resulted in the automatic actuation of the Steam Bypass Control System (JI), Reactor Power Cutback System (JD), and Power Load

Unbalance circuitry in the Main Turbine Control System (JJ). The Main Turbine-Generator continued to supply in-plant non-Class 1E loads as designed.

The Steam Bypass Control System and Reactor Power Cutback System work together following a large load rejection to allow the Unit to remain at power. The Steam Bypass Control System functions to bypass steam around the Main Turbine (TA)(TRB) during situations requiring the removal of excess Nuclear Steam Supply System energy. The Reactor Power Cutback System rapidly reduces core (AC) (RCT) thermal power output by dropping preselected Control Element Assembly (AA) (ROD) subgroups and rapidly reducing Main Turbine power output if required. The power load unbalance circuitry initiates the fast closing of the turbine control valve (FCV) and turbine intercept valve (FCV) under load rejection conditions that might lead to rapid acceleration, overspeed, and consequent tripping of the turbine. Once the power load unbalance is cleared, the control and intercept valves reopen. None of these systems are Engineered Safety Features.

During the reactor power cutback, the control system for four (4) of the eight (8) steam bypass control valves (JI)(V) did not operate properly. The control system malfunction caused these four Steam Bypass Control Valves to cycle from fully open to fully closed. This cycling resulted in a reduction of secondary pressure due to excessive steam demand. The secondary pressure reduction eventually resulted in a Steam

Generator (AB)(SG) number two (2) low pressure trip signal. The low pressure trip signal resulted in a reactor trip, Main Turbine trip, and Main Steam Isolation Signal (MSIS)(JE) Engineered Safety Feature (ESF) actuation at approximately 0103 MST. Approximately six seconds after the reactor trip, Safety Injection Actuation Signal (BP)(BQ)(JE) and a Containment Isolation Actuation Signal (JM)(JE) ESF actuations occurred due to low pressurizer (AB)(PZR) pressure resulting from the Reactor Coolant System (AB) (RCS) cooldown.

In accordance with approved procedures for the Safety Injection Actuation Signal, a Control Room operator (utility, licensed) stopped two (2) of the four (4) Reactor Coolant Pumps (RCP's)(AB)(P). Control Room personnel (utility, licensed) monitored safety functions and the Assistant Shift Supervisor (utility, licensed) diagnosed the event as an excessive steam demand pursuant to approved procedural controls. During the monitoring of safety functions, Control Room personnel observed that the Safety Equipment Status System (IU) indicated that the following valves and dampers had not fully reached their actuated positions:

HPA-UV-001 ,"Containment Hydrogen Control System 'A' Supply Isolation" (BB)(ISV);

SGA-HV-0201, "Steam Generator 2 Chemical Injection Isolation" (KD)(ISV);

SGA-UV-0223, "Steam Generator 2 Cold Leg Blowdown Downstream" (WI)(V);

SGA-UV-0225, "Steam Generator 2 Hot Leg Blowdown Downstream" (WI)(V);

SGA-UV-1134, "Steam Trap SGN-M23 Isolation" (SB) (ISV);
SGA-UV-0227, "Steam Generator 2 Downcomer Blowdown Downstream" (WI)(V);

SGB-UV-1135, "Steam Tap SGN-M02 Isolation" (SB) (ISV);

HFA-MO6, "Auxiliary Building Essential Exhaust Air Filtration Unit Damper." (VF)(DMP)

Control Room personnel also noted that the Radiation Monitoring System (RMS) displays were not available in the Control Room (NA), and that the Containment temperature (IK)(TR) and humidity recorders (IK)(MR) and sump level indicators (IK)(LI) were not available (per design) due to the loss of non-Class 1E power.

Following the Main Turbine trip, a Fast Bus Transfer of the in-plant non-Class 1E electrical loads did not occur since the conditions for initiating the automatic transfer were not present at the time of the turbine trip. Normally after a turbine trip, the main generator trips when a reverse power condition is sensed and the fast transfer of the in-plant non-Class 1E loads to the Startup Transformer occurs. As described above, the main generator was already separated from off-site power, so no reverse power condition was sensed. The main generator began to coast down after the turbine trip while still carrying in-plant non-Class 1E loads. When the generator was at a frequency of approximately 30 Hertz (approximately two minutes after the turbine trip), it tripped on Hi Volts/Hertz and initiated a Fast Bus Transfer signal. In accordance with the design, the Fast Bus Transfer signal was blocked due to the in-plant non-Class 1E loads not being in synchronization with the off-site power. Therefore, a loss of power to the in-plant non-Class 1E electrical busses (3E-NAN-SO1 and 3E-NAN-SO2) occurred. This resulted in the other two (2) RCP's being deenergized.

As a result of the Main Steam Isolation System actuation, steam flow to the main condenser (SG)(COND) through the Steam Bypass Control Valves was terminated. In order to remove decay heat without relying on the Main Steam Safety Valves (SB) (RV) or Primary Safety Valves (AB)(RV), remote operation of the Atmospheric Dump Valves (ADV's)(SB)(V) was attempted. Operation of the ADV's could not be accomplished remotely from the Control Room or the Remote Shutdown Panel (JL). Therefore, manual operation of the ADV's was attempted utilizing the valves' manual operators in the Main Steam Support Structure (MSSS). Additionally, Control Room personnel manually started the Turbine Driven Auxiliary Feedwater Pump (BA)(P) at approximately 0107 MST in order to provide an additional source of decay heat removal.

Operations personnel (utility, non-licensed) were sent to the MSSS to attempt to manually open an ADV on each steam generator (there are two ADV's on each of the two S/Gs). Normal lighting (FF) in

the MSSS was unavailable due to the loss of power to the in-plant non-Class 1E electrical busses. The single Essential Lighting fixture (FG)(LF) in the Steam Generator number 2 side of the MSSS was not functioning which resulted in almost total darkness in the area of the Steam Generator number 2 ADV manual operators. Operations personnel utilized flashlights to provide lighting while manual ADV operations were performed. At approximately 0137 MST, a steam generator number 1 ADV was opened to approximately 7 percent open. At approximately 0141 MST, operations personnel attempted to establish a steam flow path for steam generator number 2 via ADV-185. The manual handwheel for ADV-185 came off; therefore, operations personnel attempted to open ADV-179 on Steam Generator number 1. During the attempt to manually open ADV-179, the handwheel was turned in the wrong direction due to a non-standard design and the valve was damaged. Another attempt to remotely control ADV-185 was made at approximately 0200 MST. This attempt was unsuccessful. Valve control for ADV-185 was returned to manual, the handwheel reinstalled, and subsequently opened by operations personnel in the MSSS at approximately 0221 MST. Additionally, one Main Steam Safety Valve was cycling open and shut to control steam generator pressure. (It was noted by Control Room personnel that the safety was lifting approximately 30 pounds per square (psi) inch below its setpoint of 1250 psi.)

Normal pressurizer (AB)(PZR) spray was unavailable since no RCP's were running. This required the utilization of charging pumps to provide auxiliary pressurizer spray (CB). Although RCP seal injection (CB) was still being supplied by the charging system (CB), Control Room personnel isolated RCP seal bleed-off (CB) in response to the loss of Nuclear Cooling Water System (CC) (as a result of the loss of non-Class 1E power). Bleed-off flow was reestablished after it was secured by Control Room personnel. Later, Control Room personnel secured charging to prevent pressurizer level from exceeding the maximum allowed by Technical Specifications. This allowed hot reactor coolant to circulate up through the RCP seals (SEL). RCP 1B seal became degraded and began leaking prior to the restoration of seal injection.

At approximately 0139 MST on March 3, 1989, a Notification of Unusual Event (NUE) was declared pursuant to EPIP-02, "Emergency Classification," due to the loss of power to the in-plant non-Class 1E electrical busses and the Safety Injection System actuation. At approximately 0149 MST on March 3, 1989 the appropriate state and local agencies were notified via the Notification and Alert Network (NAN). The Nuclear Regulatory Commission (NRC) Operations Center was notified at approximately 0203 MST on March 3, 1989.

At approximately 0222 MST on March 3, 1989, a Steam Generator number 1 Main Steam Isolation Valve (MSIV)(SB)(ISV) bypass valve (V) was manually opened after unsuccessfully attempting to open it remotely from the Control Room. Subsequently, the two Atmospheric Steam Bypass Control Valves (SBCV's) were opened which provided an alternate steam flow path for decay heat removal. At approximately 0224 MST, Control Room personnel verified that natural circulation conditions were established. At approximately 0230 MST, a Steam Generator number 2 MSIV bypass valve was also opened which allowed decay heat removal via both steam generators. Following the establishment of decay heat removal via the SBCV's, both open ADV's were manually closed by approximately 0239 MST.

Plant recovery operations commenced. Off-site electrical power was restored to one of the in-plant non-Class 1E electrical busses (3E-NAN-SO1) at approximately 0232 MST on March 3, 1989. At approximately 0236, power was restored to the Containment Building Radwaste Sump level indication (NH)(WD)(LI). The Main Steam Isolation Signal was reset at approximately 0238 MST. The Safety Injection Actuation Signal (SIAS) and Containment Isolation Actuation Signal were reset at approximately 0241 MST. Also, off-site power was restored to the other in-plant non-Class 1E electrical bus (3E-NAN-SO2) at approximately 0243 MST restoring power availability to all in-plant non-Class 1E electrical loads.

At approximately 0300 MST on March 3, 1989, Control Room personnel observed an abnormal increase in the Containment Building Sump level. A Shift Technical Advisor (STA) (utility, non-licensed) performed a calculation and determined that there was an approximate 6 gallon per minute in-leakage into the sump. This was subsequently determined to be caused by the degraded RCP 1B seal and identified leakage from a charging line check valve (V).

As a result of restoring power to the in-plant non-Class 1E electrical busses and resetting the SIAS, the Notification of Unusual Event was terminated at approximately 0252 MST on March 3, 1989. RCP seal injection was restored at approximately 0341 MST. At approximately 0424 MST, the non-essential auxiliary feedwater pump (P) was started in order to allow securing the essential auxiliary feedwater pump. However, the Steam Generator number 1 downcomer isolation valve (V) (SGA-UV-172) could not be opened so the non-essential auxiliary feedwater pump was secured. Auxiliary feed was maintained utilizing the essential auxiliary feedwater pump. Forced circulation was re-established at approximately 0449 MST when one RCP was started. A second RCP was started at approximately 0455 MST and the event was terminated as the normal operating procedure for shutdown/cooldown from Mode 3 (HOT STANDBY) to Mode 5 (COLD SHUTDOWN) was entered.

At approximately 0815 (MST) on March 3, 1989, Control Room personnel discovered that Technical Specification Surveillance Requirement 4.5.2.g.1 had not been performed in a timely manner. Surveillance Requirement 4.5.2.g.1 states, "Each ECCS [Emergency Core Cooling System (BP) (BQ)] subsystem shall be demonstrated OPERABLE...By verifying the correct position of each electrical and/or mechanical stop for [specified] ECCS throttle valves...Within 4 hours following completion of each valve stroking operation or maintenance on the valve when the ECCS subsystems are required to be OPERABLE." The above requirement should have been performed by implementing 73ST-3SI01, "ECCS Throttle Valve Testing 4.5.2.G" within four (4) hours of resetting the Safety Actuation Injection System and closing the throttle valves at approximately 0245 MST.

Following the discovery that 73ST-3SI01 had not been performed as required, Limiting Condition for Operation (LCO) 3.0.3 was entered as a late entry at approximately 0645 MST. Surveillance Test Procedure 73ST-3SI01 was completed satisfactorily on the ECCS Train "A" throttle valves and LCO 3.0.3 was exited at approximately 0907 MST on March 3, 1989.

C. Status of structures, systems, or components that were inoperable at the start of the event that contributed to the event:

There were no structures, systems, or components inoperable at the start of the event which contributed to the event.

D. Cause of each component or system failure, if known:

The cause of the ADV malfunction is described in LER 528/89-005.

The cause of the sub-synchronous oscillation (SSO) protective relaying has not been determined. Investigation and analysis of simulated conditions at the time of the event indicate that the SSO relay should not have operated. Functional tests performed on the SSO relay and bench tests of relay circuit boards at PVNGS indicated no apparent failures or malfunctions. APS investigated possible sources of erroneous input signals to the SSO relay and could not determine the cause of the relay operation. If information is developed which would lead to a determination of the cause, a supplement to this report will be submitted to describe the results of the investigation.

The cause of the Steam Bypass Control System (SBCS) malfunction described in Section I.B has been determined to be a failed auto permissive delay timer card (69) in the SBCS control circuitry.

The timer card failure was caused by a malfunctioning integrated circuit on the card.

With the exception of damper HFA-MO6, the cause of the Safety Equipment Status System (SESS) indication that the valves and dampers described in Section I.B had not fully reached their actuated positions could not be determined. Troubleshooting performed in accordance with an approved work authorization document on damper HFA-MO6 determined that the damper operated properly; however, a position indicator limit switch (ZIS) was out of adjustment. The limit switch was readjusted and satisfactorily tested. Troubleshooting performed in accordance with approved work authorization documents determined that SESS and the other individual components listed in Section I.B operated properly. No component failures to actuate were discovered.

The cause of the Main Steam Safety Valve (MSSV) lifting approximately 30 psi below its setpoint could not be determined. The valve was removed and sent off-site for setpoint adjustment, rework and root cause analysis. The valve was sent to Wyle Laboratories and a representative from the valve manufacturer (Dresser) was present. No cause for the valve lifting below its setpoint could be established by Dresser and Wyle. Several hypotheses were provided concerning why the valve may have lifted early; however, none provide a supportable, definitive reason for the valve's operation. It should be noted that 30 psi is within the valve manufacturer's specifications for setpoint tolerance. The manufacturer's specification for the sepoint is 3 percent. Additionally, Dresser stated that field testing to a 1 percent tolerance is not practical.

The cause of RCP seal bleed-off flow being re-established could not be determined. Troubleshooting on CHA-UV-SO7, "Seal Bleed-off Isolation Valve," determined that the valve performs as designed.

The cause of Steam Generator No. 1 Isolation Valve SGA-UV-172 not opening is indeterminate. APS engineering performed an investigation in accordance with the APS Root Cause of Failure Program. During subsequent troubleshooting and investigation, the valve operated properly. No deficiencies or malfunctions were noted with any of the valve's components.

The cause of not being able to operate the Steam Generator Number 1 MSIV bypass valve remotely from the Control Room could not be determined. APS engineering performed an investigation of the valve's operation in accordance with the APS Root Cause of Failure Program. During subsequent troubleshooting and investigation of

the valve's operation from the Control Room, the valve operated properly.

E. Failure mode, mechanism, and effect of each failed component, if known:

The failed auto permissive delay timer card in the Steam Bypass Control System (SBCS) control circuitry resulted in several successive "quick open" and rapid closures of the SBCS valves. The valve cycling resulted in periodic excessive steam demand which caused steam generator pressure to decrease. The decreasing steam generator pressure resulted in the reactor trip, main turbine trip, and ESF actuations described in Section I.B.

The failure of the Atmospheric Dump Valves (ADV's) to operate properly from the Control Room or the Remote Shutdown Panel resulted in one Main Steam Safety Valve lifting to control steam generator pressure and remove decay heat. The failure mode and mechanism are described in LER 528/89-005.

The failed light bulb in the Main Steam Support Structure Essential Lighting described in Section I.B resulted in inadequate lighting in the area of the Steam Generator number 2 ADV manual operators. This contributed to operators turning the handwheel the wrong way and damaging ADV-179.

The failure of the Steam Generator number 1 downcomer valve to open resulted in the inability to utilize the non-essential auxiliary feedwater pump to feed the steam generators for decay heat removal. It should be noted that use of the non-essential feedwater pump is an elective measure and is not credited in the safety analysis for safe shutdown.

The failure of the Steam Generator number 1 MSIV bypass valve to open remotely from the Control Room resulted in the inability to utilize this flowpath for decay heat removal. It should be noted that use of this flowpath is an elective measure and is not credited in the safety analysis for safe shutdown.

F. For failures of components with multiple functions, list of systems or secondary functions that were also affected:

Not applicable - no component failures had multiple functions which affected other systems or components.

G. For failures that rendered a train of a safety system inoperable, estimated time elapsed from the discovery of the failure until the train was returned to service:

1. The failure of the auto permissive delay timer card in the Steam Bypass Control System (SBCS) did not render a train of a safety system inoperable (the SBCS is not a safety system).

2. The failed light bulb in the Main Steam Support Structure Essential Lighting was discovered at approximately 0130 MST on March 3, 1989, during the event as discussed in Section I.B. The light bulb was replaced on March 10, 1989. Therefore, the Essential Lighting was out of service for approximately 7 days from the time of discovery until it was returned to service due to equipment in the area being quarantined.

3. The Atmospheric Dump Valves (ADV's) were discovered to be inoperable at approximately 0105 MST on March 3, 1989 as described in Section I.B. The ADV's remained inoperable following this event as Unit 3 began a refueling outage. Modifications to the ADV's have been completed. The ADV's were restored to service following completion of the appropriate retesting (Reference LER 528/89-005).

H. Method of discovery of each component or system failure or procedural error:

1. The Steam Bypass Control System auto permissive time delay timer card failure was discovered as a result of

troubleshooting performed after the event.

2. The Atmospheric Dump Valve malfunctions were discovered by Control Room personnel during the event as described in Section I.B.

3. Evidence of the Reactor Coolant Pump seal degradation was observed by Control Room personnel during the event. Subsequent investigation confirmed that RCP seal degradation was the cause of the Reactor Coolant System leakage.

4. The failed light bulb in the Main Steam Support (MSSS) Essential Lighting was discovered during the post-event investigation of the cause of inadequate lighting in the MSSS during the event.

5. The Steam Generator No. 1 Downcomer Isolation Valve, SGA-UV-172, malfunction was discovered during the event as described in Section I.B.

6. The Steam Generator number 1 MSIV bypass valve malfunction was discovered during the event as described in Section I.B.

7. There were no procedural errors which contributed to the reactor trip or ESF actuations described in Section I.B; however, based upon the APS post-event investigation of

the event several procedure enhancements were deemed appropriate.

8. The procedures for recovering from a Safety Injection System actuation did not provide guidance for performing the surveillance in a timely manner. This procedural deficiency was discovered during a Human Performance Evaluation System (HPES) performed as a result of this event.

I. Cause of Event:

The cause of the reactor trip and Engineered Safety Features actuations described in Section I.B was a malfunction of the Steam Bypass Control System (SBCS). Further information concerning the cause of the SBCS malfunction is contained in Sections I.D. through I.H.

The cause of the condition prohibited by the plant's Technical Specifications wherein Control Room personnel (utility, licensed) did not perform Surveillance Requirement 4.5.2.g.1 in a timely manner is a personnel error resulting from the complex sequence of events, the need for Control Room personnel to ensure that the plant was in a stable condition, and that the procedures for recovering from a Safety Injection System actuation did not specifically address the surveillance requirement (i.e., the recovery procedures did not provide guidance for performing the surveillance in a timely manner). Other than discussed in Section I.B, there were no unusual characteristics of the work location (e.g., heat, noise, smoke, poor lighting, etc.) which contributed to this event.

J. Safety System Response:

The following automatic and manual safety system responses occurred during this event:

1. Containment Isolation System (automatic)(JM).
2. Low Pressure Safety Injection Trains "A" and "B" (automatic) (BP)
3. High Pressure Safety Injection Trains "A" and "B" (automatic)(BQ)
4. Main Steam Isolation System (automatic)
5. Emergency Diesel Generators Trains "A" and "B" (automatic) (DG) (EK)
6. Essential Spray Pond System Trains "A" and "B" (automatic) (BS)
7. Essential Chilled Water System Trains "A" and "B" (automatic) (KM)

8. Essential Cooling Water System Trains "A" and "B" (automatic) (BI)
9. Condensate Transfer System Trains "A" and "B" (automatic) (KA)
10. Containment Spray Trains "A" and "B" (automatic) (BE)
11. Auxiliary Feedwater System Trains "A" and "B" (automatic and manual) (BA)

K. Failed Component Information:

The malfunctioning Atmospheric Dump Valves were manufactured by Control Components Incorporated. They are model number B3G9-10-12P8-31NAS1.

The failed auto permissive delay timer card in the Steam Bypass Control System is manufactured by Allen-Bradley Company. The card model number is 1720-L410.

The failed light bulb in the Main Steam Support Structure was manufactured by QSR Industrial. The light bulb model number is 500 watt permalux.

II. ASSESSMENT OF THE SAFETY CONSEQUENCES AND IMPLICATIONS OF THIS
EVENT:

This assessment addresses the impact of the Unit 3 load reject/low steam generator pressure reactor trip event described above from the perspective of compliance with the design bases events presented in Chapters 6 and 15 of the PVNGS Final Safety Analysis Report (FSAR). This event was first characterized as an "increase in heat removal by the secondary system" due to the Steam Bypass Control System (SBCS) valves cycling. Later the event progressed to a "decrease in heat removal by the secondary system" type event caused by the Main Steam Isolation Signal (MSIS) with inoperable Atmospheric Dump Valves (ADV).

The design criteria of concern for an increase in heat removal by the secondary system event would be a violation of the Specified Acceptable Fuel Design Limits (SAFDL's). These events cause a decrease in the temperature of the reactor coolant, an increase in reactor power due to the negative moderator temperature coefficient and a decrease in reactor coolant system and steam generator pressures. A review of the transient data for the period during the transient demonstrated that no violation of the SAFDL's occurred. Sufficient conservatisms were applied in the limiting design bases event to adequately bound the Unit 3 transient. The most limiting conservatism is that the overcooling due to heat removal through the SBCS valves was less than the heat removal that is assumed in either the Main Steam Line Break design bases event or the Inadvertent Opening of a Steam Generator Safety Valve anticipated operational occurrence.

For an event characterized by a decrease in heat removal by the secondary system, the design criterion of concern is a violation of the reactor coolant system (RCS) and steam generator design pressure limits. The decrease in the heat removal event causes an increase in RCS temperature and pressure. The Unit 3 heat-up event described in Section I.B was initiated after the reactor tripped on low steam generator pressure with a concurrent MSIS. The transient data indicates that main steam flow stopped for a brief period of time during which primary pressure increased (as expected). Review of this pressure spike confirmed that Unit 3 did not experience a heat-up event greater than those previously analyzed and documented in the FSAR. The maximum RCS pressure remained well below the design limit.

Overall, the response of the Unit was complicated due to the malfunctioning of the SBCS and the ADV's. The effects of these malfunctions did not cause the Unit to experience initial conditions or consequences any more adverse than those previously analyzed in the PVNGS FSAR.

The SBCS and Reactor Power Cutback System (RPCS) are not safety grade systems and are therefore not credited in Safety Analyses. Thus, the steam relief that the SBCS provided in combination with the reduced reactor power due to the proper functioning of the RPCS, only served to move the unit further away (i.e. in a more conservative direction) from the initial conditions assumed in the Safety Analyses.

The PVNGS Safety Analysis assumes operation of the ADV's for long term heat removal and cooldown and the ADV's are not credited in Chapter 15 events until 30 minutes after the initiating event. For long term cooling, only one ADV per steam generator is assumed available for the duration of the event in the safety analysis. The Unit 3 Operations personnel were able to open one ADV per steam generator. Had the operators not been able to open the ADV's, the Main Steam Safety Valves (MSSV) would have prevented overpressurization of the steam generators and increased heat-up of the RCS. (Note: One of the twenty (20) MSSV's actuated to prevent overpressurization during the Unit 3 event described in this LER.) During an analyzed transient, the MSSV's are assumed to operate and provide secondary heat removal. Reactor decay heat is removed through the cycling of the MSSV's. The MSSV's will continue to cycle in this manner keeping the RCS in a hot standby condition.

The fact that the MSSV first lift setpoint was lower than expected was in the conservative direction. Also the safety grade steam turbine driven auxiliary feedwater pump which was started aided in the heat removal process. If Control Room personnel had not initiated feed to the steam generators, the auxiliary feedwater actuation signal (AA) (JE) would have occurred and initiated feed to the steam generators. Both essential auxiliary feedwater trains were operable and fully available.

Due to the relief of secondary side steam to the atmosphere, there is a potential for releasing radioactive material to the environment. For the event described in Section I.B, the most probable source would have been a primary to secondary steam generator tube leak. All analyses that evaluate for off-site dose criteria assume as initial conditions one percent fuel failure and a minimum Technical Specification primary to secondary leak of 1 gallon per minute (gpm). Prior to the Unit 3 event there was no identified leakage greater than 1 gpm and present chemistry data estimates only 1-2 failed fuel pins. Also, an analysis of data obtained during the event determined that no releases in excess of Technical Specification limits occurred. Therefore, the off-site dose consequences of the Unit 3 event are bounded by analyzed events documented in the PVNGS FSAR.

In summary no violations of the fuel design limit, primary pressure boundary limit, and 10CFR100 off-site dose limit criteria were exceeded. Therefore, there were no safety consequences or implications resulting from the event described above.

III. CORRECTIVE ACTIONS:

A. Immediate:

Immediate corrective actions taken by Operations personnel to stabilize the plant are described in Section I.B.

B. Action to Prevent Recurrence:

As described in Section I.D and I.I, the cause of the reactor trip and ESF actuations was a malfunction in the Steam Bypass Control System (SBCS). As corrective action, the malfunctioning component has been replaced. Additionally, an engineering evaluation of the SBCS was conducted. APS engineering concluded that, although the SBCS in use at PVNGS is somewhat unique in the industry, it is performing as designed and the design utilized is consistent with the overall design objectives of the plant. The results of the engineering evaluation were provided with APS's response to the PVNGS March 1989 Augmented Inspection Team Report dated May 18, 1989 (Reference: 102-01285-WFC/TDS/SCT/RAB dated May 29, 1989) and describe additional corrective measures which are being implemented in accordance with pre-established schedules.

As described in Section I.I, the cause of the condition prohibited by Technical Specifications wherein a Surveillance Requirement was not performed in a timely manner was a personnel error. As corrective action, the appropriate procedures for recovering from a Safety Injection System actuation have been revised to provide guidance for performing the surveillance in a timely manner.

An independent investigation of this event was conducted in accordance with the PVNGS Incident Investigation Program. The results of this investigation were provided with APS's response to the PVNGS March 1989 Augmented Inspection Team Report dated May 18, 1989 (Reference: 102-01285-WFC/TDS/SCT/RAB dated May 29, 1989). The investigation describes the corrective actions for the concerns which arose as a result of the event. The corrective actions are being implemented in accordance with pre-established schedules.

Due to concerns about Emergency and Essential Lighting System operation, an engineering evaluation of the Emergency and Essential Lighting System was performed. The results of this evaluation were provided with APS's response to the PVNGS March 1989 Augmented Inspection Team Report dated May 18, 1989 (Reference: 102-01285-WFC/TDS/SCT/RAB dated May 29, 1989). Based upon the results of this investigation, enhancements and corrective actions were developed and are being implemented in accordance with pre-established schedules. Additionally APS discovered that the Emergency Lighting System did not meet the design bases in the PVNGS Updated Final Safety Analysis Report (UFSAR) and was reported in LER 528/89-012. Further corrective actions are described in LER 528/89-012.

As a result of the ADV malfunctions described in Section I.B, engineering evaluations of the Compressed Gas System and ADV's were performed. The results of these investigations were provided with APS's response to the PVNGS March 1989 Augmented Inspection Team Report dated May 18, 1989 (Reference: 102-01285-WFC/TDS/SCT/RAB dated May 29, 1989). Based upon the results of these evaluations, corrective actions were developed and are being implemented in accordance with pre-established schedules. Additionally during the investigation of the ADV problems, APS became aware of a defect reportable pursuant to 10CFR21 which was reported in LER 528/89-005. Further corrective actions are described in LER 528/89-005.

IV. PREVIOUS SIMILAR EVENTS:

There have been previous reactor trip events reported pursuant to 10CFR50.73 contributed to or caused by malfunctions occurring in the Steam Bypass Control System; however, none of the previously reported events involved a failure of the auto permissive delay timer card.

V. ADDITIONAL INFORMATION

There has been one accumulated actuation cycle of the Emergency Core Cooling System to date. This report satisfies the requirements of Technical Specification 3.5.2 ACTION b.

ATTACHMENT 1 TO 9002120163 PAGE 1 OF 1

Arizona Public Service Company
PALO VERDE NUCLEAR GENERATING STATION

P.O. BOX 52034 PHOENIX, ARIZONA 85072-2034

JAMES M. LEVINE
VICE PRESIDENT 192-00624-JML/TRB/DAJ
NUCLEAR PRODUCTION January 28, 1990

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Unit 3
Docket No. STN 50-530 (License No. NPF-74)
Licensee Event Report 89-001-03
File: 90-020-404

Attached please find Supplement Number 3 to Licensee Event Report (LER) No. 89-001-00 prepared and submitted pursuant to 10CFR50.73. In accordance with 10CFR50.73(d), we are herewith forwarding a copy of the LER to the Regional Administrator of the Region V office,

If you have any questions, please contact T. R. Bradish, (Acting) Compliance Manager at (602) 393-2521.

Very truly yours,

JML/TRB/DAJ/kj

Attachment

cc: W. F. Conway (all w/a)

E. E. Van Brunt

J. B. Martin

D. Coe

M. J. Davis

A. C. Gehr

INPO Records Center

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